The influence of power density on the value chain

An offshore case study

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***Abstract*— The power density of a wind turbine has an influence further down the value chain of energy. Some of these effects are presented in this paper, based on an offshore case study.**

***Keywords-** power density; capacity factor; offshore wind energy; value chain of wind energy; cost of energy; year to year energy yield variation*

I. Introduction

The power density of a wind turbine is defined as its rated power divided by its swept rotor area. Both are key design parameters that are to be chosen by the wind turbine designer. The underlying design considerations may typically include considerations on energy yield, wind climate, structural loads and component costs.

It is recognized that power density also has an influence further down the value chain of wind energy. In order to investigate some of these effects, a case study has been made for an offshore case. The results are presented here.

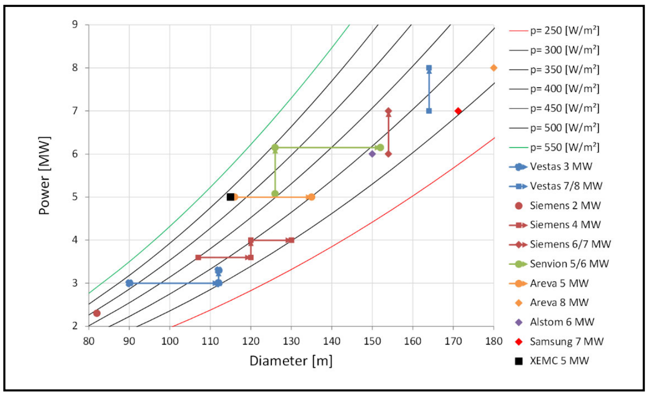
This work was part of the project 'Dynamic Power Management', supported by TenneT TSO, and by the Dutch research program 'Far and Large Offshore Wind'. The complete work was reported in [1].

II. Market trends in power density for offshore wind turbines

In the onshore wind turbine market, there is a clear trend towards lower power densities. For example, less than 10 years ago, a turbine in the 2 megawatt class would have a rotor diameter of typically around 90 meters, whereas nowadays it typically has a rotor diameter over 110 meters. This trend is driven by the expanding market of mid and low-wind speed sites.

In the offshore wind turbine market, the picture is less clear. Figure 1 shows the turbines in the market in a power-diameter diagram, including the stepwise upgrades that were developed for the turbine platform. Sometimes the diameter was increased, leading to a lower power density, and sometimes the rated power was increased, leading to a higher power density.

Figure 2 shows the same turbines with the power density and the year of prototype installation. It can be seen that approximately 10 years ago the power density was typically between 400 and 475 Watts per square meter, whereas recent turbines have a power density typically between 300



and 375 Watts per square meter. However, in the last five year, no

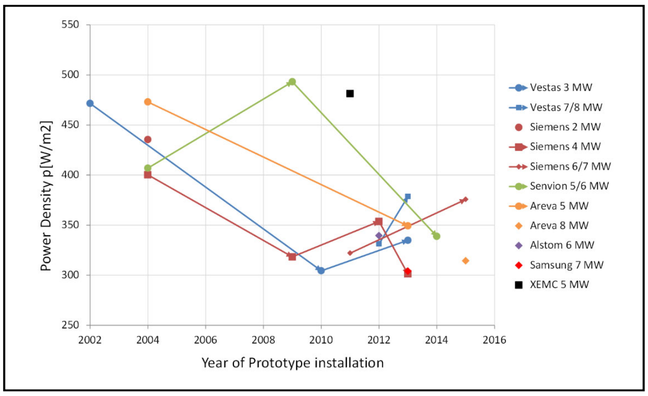
Figure 1. Power-diameter diagram for turbines in the offshore market. Including isolines for power density

Figure 2. Power density for turbines in the offshore market, as a function of year of prototype installation

clear trend can be detected, as the power densities go up and down, due to new platform releases.

III. The relation between power density and capacity factor

The capacity factor of a wind turbine is defined as its average power performance divided by its rated power. In case rated power is increased, average power also increases,



however less than linear with the rated power. As a consequence, the capacity factor decreases for increasing power density.

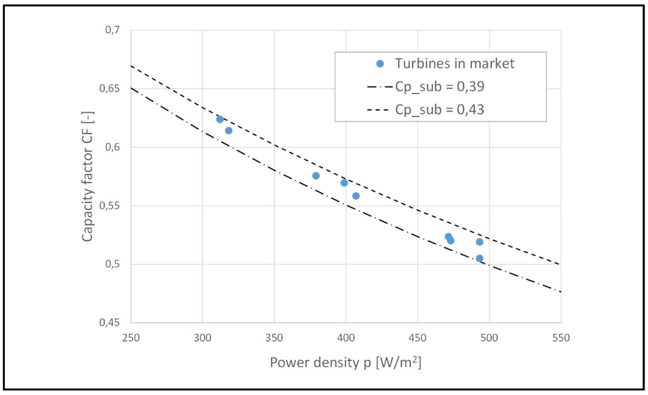


Figure 3. Relation between power density and capacity factor, for different turbines in the offshore market. Average wind speed 10m/s. No losses are assumed.

The power density and capacity factor can be found for any turbine with a given power curve in a given wind regime. This is done for a number of turbines in the market, and presented in figure 3. No cable or unavailability losses are assumed. The average wind speed is assumed to be 10 meters per second.

It is shown that there is a clear relation between the power density and the capacity factor. Secondly, there is also the influence from the power coefficient of the turbine Cp below rated wind speed. A parameter, called Cp_subrated, can be formulated to express the aerodynamic, mechanical, electrical and control efficiency of the turbine below rated wind speed in one single parameter. All turbines fall within a small bandwidth given by both dotted lines. These dotted lines reflect the situations where Cp_subrated equals 0.39, resp. 0.43. All turbines are within this bandwidth, independent of the power density.

The capacity factor translates directly into the utilization rate for the electrical infrastructure. A capacity factor of 50% means that on average, the electrical cabling, transformers, switches, and so on are only used half of their maximum capacity, whereas the costs remain the same.

In conclusion, a lower power density leads to a higher capacity factor and a higher utilization rate of the electrical infrastructure.

IV. Influence of Power Density on the Cost of Energy – Case Study

The cost of energy is determined by the energy yield of a wind farm and by the total costs related to this wind farm. Both energy yield and costs influenced by the rotor diameter and the rated power.

A. Far and large offshore power plant

This influence is investigated for a fictive, but realistic windfarm of 900 megawatt with 112 fictive, but realistic reference wind turbines of 8 megawatt each. It is located on the Dutch part of the Dogger Bank. The distance to shore is approximately 300 kilometers. The average wind speed is considered to be 10.7 meters per second. The turbines are oriented in a rectangular grid of 13 times 8 rows, with an intermediate distance of 1 kilometer. The wind turbines have a diameter of 164 meters, which corresponds to one of the largest turbines in the market.

Based on this reference case, different variants with different combinations of rotor diameter and rated power have been analysed. The power curve of each turbine variant is generated artificially with a Cp_subrated of 0.41. The power performance of the wind power plant is calculated with FarmFlow [2].

B. Cost modelling

The total costs of a wind farm project consist of many elements, which all depend on several parameters. In order to gain understanding how the cost of energy is influenced by the rated power and the rotor diameter, a proper cost model should be used. These models are not commonly available and therefore a specific cost model has been developed for the purpose of this work. The model is based on the costs of a reference case, and its gradients for the variables diameter and rated power. Each cost equation is then written as a function of the diameter and the rated power.

The turbine costs are the sum of the component costs. As the key components of the turbine are designed to either withstand the loads or transport the power, their costs are directly dependent on the rotor diameter and the rated power. This has been worked out for all key turbine components, leading to a cost equation for each component of the following shape.

$$C_{comp} = C_{comp,ref} * \left(\frac{D}{D_{ref}}\right)^{a} * \left(\frac{P}{P_{ref}}\right)^{b} \qquad (1)$$

With:
Ccomp, Ccomp,ref [k€]: component costs and its reference
D, Dref [m]: diameter and its reference
P, Pref [kW] : rated power and its reference

The resulting factors a and b, and the estimated reference cost, as defined in (1) are given in table I, for each component. The last row gives the result for the whole turbine.

TABLE I. CONSICE COST MODEL FOR FICTIVE 8 MW, 164M TURBINE

Component	$C_{comp,ref}$ [k€]		a [-]	b [-]
Blades	3397 k€	20.7%	2	0.5
Pitch systems	530 k€	3.2%	3	0.5
Hub	232 k€	1.4%	2.2	0.6
Main shaft, bearings	453 k€	2.8%	1.8	0.5
Brake system	150 k€	0.9%	0	1
Gearbox	1656 k€	10.1%	0.8	0.8
Nacelle bed	426 k€	2.6%	1.67	0.67
Nacelle cover, O&M systems, H&S systems	21 k€	0.1%	0	0.2
Nacelle assembly	63 k€	0.4%	0	0.5
Yaw system	189 k€	1.2%	1.67	0.67
Electrical system	1486 k€	9.1%	0	1
Control system	30 k€	0.2%	0	0

Tower	3068 k€	18.7%	0.67	0.67
Support structure	4705 k€	28.7%	0.67	0.67
Total turbine	**16408 k€**	**100.0%**	**1.05**	**0.67**

TABLE II. BASELINE COST SUMMARY FOR WIND POWER PLANT

	Costs for wind power plant (112 turbines)	
Turbines	1837.7 M€	44.6 %
Transport & Installation	56.0 M€	1.4 %
Elec. Infra		
- *In-field cabling*	*52 M€*	
- *Integration*	*496 M€*	
- *Transmission*	*480 M€*	
- *Grid interface*	*165 M€*	
Subtotal	1193 M€	28.9 %
Other investment costs	112 M€	2.7 %
O&M costs	878.1 M€	21.3 %
Decommissioning costs	44.5 M€	1.1 %
Total	**4121.3 M€**	**100.0 %**

Summation of the components leads to cost function (2).

$$C_{turb} = 16408\ k€ * \left(\frac{D}{164\ m}\right)^{1.05} * \left(\frac{P}{8\ MW}\right)^{0.67} \quad (2)$$

The costs for the other parts of the complete wind power plant are estimated, based on interpretation of limited market information. For the O&M costs, the net present value is used for a period of 20 years and an interest rate of 8%. The electrical infrastructure is defined up to the onshore grid connection. The cost summary is given in table II. It is assumed that the costs of the electrical infrastructure are linear with the rated power of the wind power plants.

C. Turbine variants

Based on the reference turbine (8 megawatt and 164 meter), eight alternative turbine variants were defined, with 10% smaller or larger diameter and 10% smaller or larger rated power. Figure 4 shows all nine variants and the power density isolines. The power density of the different variants vary from 282 to 514 Watt per square meters.

These nine variants lead to nine wind power plant variants. For each of these the costs and the annual energy production are calculated. The turbine availability is assumed to be 92% and the total electrical losses 6%. The net present value of the annual energy production during a period of 20 years is calculated, based on an interest rate of 8%.

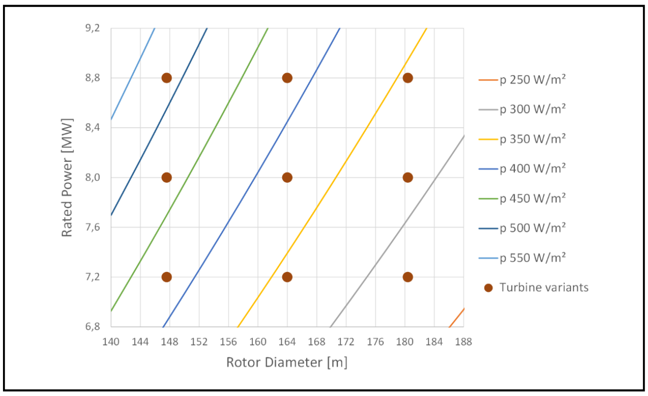


Figure 4. Power density isolines and nine turbine variants in power-diameter graph

D. Levelised cost of energy

Dividing the net present value of the energy during its lifetime by the total costs, leads to the Levelised Cost of Energy or LCOE. Figure 5 gives the results when only the turbine costs are taken into account. The LCOE appears to be lower for smaller diameters, whereas it is less sensitive in variations in rated power.

The picture changes when the other costs from table II are taken into account, as shown in figure 6. Now, a larger diameter leads to lower LCOE. This is explained by the fixed overhead costs that have to be taken anyway. Thus it makes more sense to increase the energy yield by a larger diameter. A higher rated power is also beneficial, however less convincing, since the costs for the electrical infrastructure grows proportionally.

It is recognized that the costs to be made for the electrical infrastructure may not be limited to the electrical components up to and including the grid connection. It may be required to strengthen the grid itself as well. These costs are typically socialized, i.e. paid by the State. Still these costs should be taken into consideration, since it is a direct result of the wind power plant. In the following analysis, it is assumed that the additional costs for the grid are the same as the costs up to the grid connection. The results are given in figure 7. It is seen that the benefit of a larger rotor diameter increases further, and the benefit of higher rated power more or less disappears. Furthermore, it is seen that, for a given diameter, the power density at which the lowest cost of energy is achieved, decreases for increasing diameters.

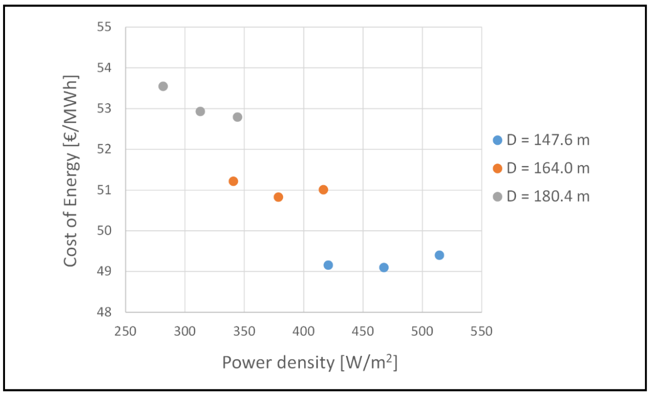


Figure 5. Cost of energy versus power density. Only turbine costs taken into account.

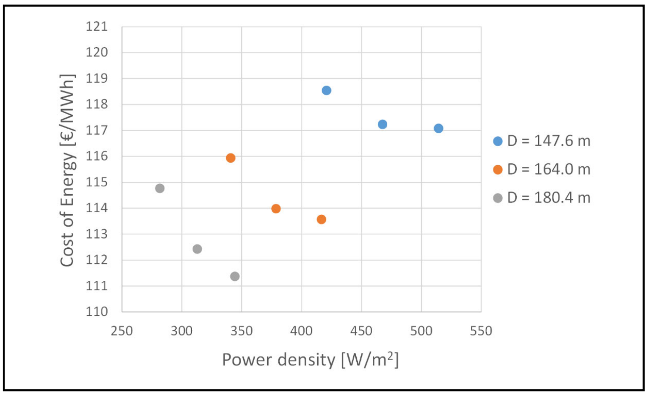


Figure 6. Cost of energy versus power density. Costs up to and including the grid connection are taken into account.

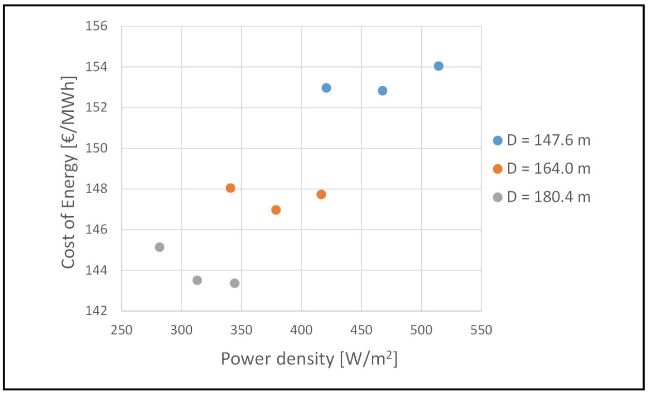


Figure 7. Cost of energy versus power density. Costs include strengthening of the grid.

As a general conclusion, it can be stated that the optimum combination of rotor diameter and rated power is influenced by the costs of the electrical infrastructure that are taken into account. More costs of electrical infrastructure leads to the preference of larger rotor diameters and lower power densities.

V. The Influence of Power Density on Year to Year Energy Yield Variation

The average wind speed varies from year to year, which results in an uncertain return on investment for the investor. In order to quantify this uncertainty, all nine variants were analysed for an average wind speed of 10.7 meters per second (representative for North Sea locations far offshore [3]), and an average wind speed of 9.7 meters per second, representing a lower wind year in the same location. The results are shown in figure 8. Obviously, the energy yield has reduced during the lower wind year, leading to a higher cost of energy. However, the effect is not the same for all variants. It is seen that lower power density leads to lower energy yield sensitivity for low wind years.

Figure 9 presents the same results as a relative change in cost of energy for the different variants. For a power density of 500 Watts per square meter, the cost of energy increase is 15.5%, whereas for 300 Watts per square meter, the cost of energy increase is 12.0%. This means that the risk of a low wind year has reduced 23% (1-12.0/15.5%) for turbines with a power density of 300 Watts per square meter compared to turbines with 500 Watts per square meter.

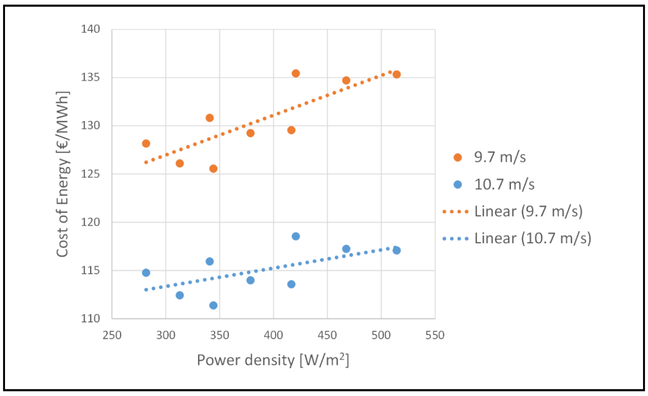


Figure 8. Cost of energy versus power density for 9.7m/s and 10.7 m/s average wind speed.

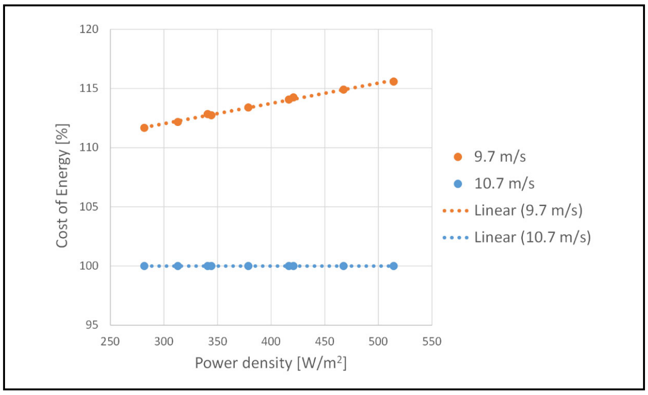


Figure 9. Cost of energy versus power density for 9.7m/s relative to 10.7m/s average wind speed.

This finding has a general validity: Lower power density leads to lower cost of energy sensitivity for year-to-year wind speed variation. This leads to reduced risk for the investor, and reduced uncertainty in the energy markets.

Variation in wind is given by nature, but variation in wind energy can be influenced by design.

VI. Conclusions

The trend towards a lower power density, as seen in the onshore market, is not seen in the offshore market for wind turbines in recent years.

A lower power density leads to a higher capacity factor, which translates directly to the utilization rate of the electrical infrastructure.

The optimum combination of rotor diameter and rated power is influenced by the costs of the electrical infrastructure that are taken into account. More costs of electrical infrastructure leads to the preference of larger rotor diameters and lower power densities.

Lower power density leads to reduced sensitivity for year-to-year wind speed variation, which leads to reduced risk for the investor, and reduced uncertainty in the energy markets.

References

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